REVIEW OF CASE HISTORIES IN HYDRAULIC LIFT FOR DIFFERENT WELL CONDITIONS TO DEMONSTRATE THE IMPORTANCE OF INTEGRATED DESIGN AND EQUIPMENT SELECTION

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ABSRACT

Hydraulic lift has been used successfully in many oil wells worldwide since the mid 30's. Many combinations of well completions and different component configurations provide a wide range of production and lift capacity with solutions to different well conditions including heavy oil, sand and gassy production with potential to provide a lift design suitable for the life of the well. A review of several actual applications with particularities that made them work may increase awareness of the problem solving potential of this system.

Integrated engineering practices are a major key to success. Transient parameters such as reservoir pressures that may guide design of artificial lift systems during early phases of production often after stimulation produce above the saturation point, but decline can be 40% to 60% within the first 12 to 18 months of production. An artificial lift system ideally serves the needs of the well throughout the life of the well, but it can only be accomplished with a holistic approach to design where all available information including reservoir pressure decline and maintenance plans are considered to meet the needs of the well with the best life cycle and ROI.

Hydraulic lift professionals question why the industry fails to consider hydraulics more often, but analysis leads to recognition of a need for more training, integrated engineering and product development.

This review of case histories with solutions to common problems will hopefully lead to a reawakening and further product development of a system that has the potential to produce at lower cost and provide solutions to the industries new challenges. Many of the solutions outlined herein have been around for decades but too often fail to be considered where they are needed. In order to provide more insight on hydraulic lift, it is assumed that other lift systems were considered and that hydraulic lift was selected to proceed with design and equipment selection. The basics with features and benefits offered by hydraulic lift are included for review.

BACKGROUND

The idea of organizing concepts presented here is based on investigative work that was done to recover oil from a mature oilfield that had been produced for almost a century with a total of 490 wells. Preliminary engineering indicated the need for re-entry and new drilling that had to done at low cost.

The search for reduced cost led to slim hole or reduced bore drilling concepts; however, reducing the cost of penetrating oil reserves had to be complemented with an artificial lift system that can pump from reduced diameter, low pressure, sandy and gassy wells without compromising production rates.

Hydraulic lift was selected because the system also offers the potential to set the pump deep into directional or horizontal wells and provides a means to run the pump in the well without pulling tubing for well testing or permanent production.

Transient parameters include production rate, water cut, reservoir pressure, gas production and sand content. Production after re-entry, drilling and/or stimulation could be above the saturation point with a possible rapid decline.

Review of recent hydraulic jet pump applications identified a well completion design that has proven successful in unconventional wells for flow back and in some cases permanent production while the simplest “casing free” well completion works satisfactorily during flow back and early stages of production, but often fails to meet objectives a year later. A closer look at hydraulic well completions provides additional insight.

There is special volume jet pump downhole equipment suited for high volume water drive reservoirs. Reservoirs that provide pump intake pressures at or above 100 psi per thousand feet of lift and low gas production can be pumped economically and reliably with high volume casing free well completions, but low pressure gassy wells may require downhole gas separation and gas vented well completions. In some cases the gas vented completion can serve the needs of the well from start up. Gas vented completions are also used to dewater gas wells.

The introduction of coil tubing adds convenience to gas vented completions. The well completion requires an integrated design approach to provide a reliable completion. This design is covered in more detail as well as a review of the different well completions.

HYDRAULIC LIFT BASICS

A quick review of hydraulic artificial lift is included for review. Note that many solutions that serve needs today were first presented in text books in the 60’s.

Hydraulic pumping systems transfer energy in the way of high pressure fluid or power fluid discharged from a surface power unit injected downhole to the subsurface pump, as shown in Figure 1.0. The subsurface pump operation transfers sufficient energy to produce fluids to flow both to the surface.

Single wells or multiple wells can be power by one or multiple surface power units. This is not a new concept. Figure 2.0, the illustration shows a multiple well power fluid-control manifold used to control the operation of several hydraulic pumps published in 1961.

Well completion options provide solutions for reduced bore wells, low pressure wells, high gas production, high volume, heavy oil and sand or corrosion. The pump can be fixed or retrievable by reverse flow, “RIG LESS”.

Figure 3.0 is taken from book 2b of the Kermit Brown Artificial Lift Methods collection copy wright 1980 to demonstrate that different well completion solutions are not new to the industry but their application are often overlooked or selection fails to consider transient well parameters resulting is failure to provide satisfactory operation as conditions change. Prudent review also identified potential upgrades with technology available today.

The subsurface pump can be a positive displacement reciprocating piston pump or a jet pump. Jet pumps can be designed to fit in the same piston pump landing cavity or bottom hole assembly. Diagrams of the two pumps are shown in Figure 4.0.

PISTON PUMP

The piston pump is an efficient positive displacement pump ideal for low-pressure reservoirs that requires cleaner power fluid and has lower tolerance to gas, corrosion, and sand.

Piston pumps can reduce the energy required to produce a low-pressure reservoir. Performance calculations are included in this report for comparison with jet pumping. Piston pump design was developed in the early 30’s and remains essentially the same. There a few changes introduced in recent years as a result of unconventional reservoir activity, but there is much more that needs to be done. This is a high efficiency tool that can serve the needs of recovering hydrocarbons from deep horizontal wells, a major concern in most artificial lift conferences.

JET PUMP

The jet pump uses the venturi effect through high-pressure fluid or power fluid injected from the surface to draw fluid from the formation and exchange sufficient energy to pump the fluid to the surface. Power fluid enters the jet pump nozzle where pressure head is converted to velocity head in the decreasing area of the nozzle so the high-speed discharge at the nozzle reduces static pressure drawing formations fluids into the mixing tube or throat where fluids mix. The increasing area that follows in the diffuser converts the homogeneous mixture velocity head to sufficient pressure head to reach the surface. Different size nozzles and throats are available and can be combined to provide a variety of production and lift capacity.

Figures 5.0 and 6.0 demonstrate the relationship between nozzle and throat and how they can be combined to provide different lift and volumetric capacities.

A common question is; “How much can a jet pump produce?” Well casing and tubing limit the amount of fluid that can circulate in a well with acceptable pressure losses. Increased losses at the jet pump discharge require increased input energy and incur mixing losses in the energy exchange. Standard and high volume jet pump models are described later in the document, but these models are also available for the different standard tubing sizes where combinations work best when flow areas are greater at the discharge of the pump. Surface operating pressures have been traditionally limited to 5000 psi, but new technology is available to consider higher pressures today. For any given nozzle the greater horsepower that can be made available today is the result of flow through that nozzle or orifice at 5000 psi surface operating pressure. This pressure added to the weight of power fluid above the pump less frictions losses provide the pressure at the nozzle. The pump intake pressure at the other end of the nozzle provides parameters needed to determine the amount of power fluid that can go through the nozzle area. This nozzle discharge jet combined with a small throat acts on a small area to provide more lift per horsepower used or the same can be combined with a large throat to allow larger produced volumes but the reduced power fluid per barrel of produced fluid results in a lower differential pressure on the production. Pump intake pressure, gas production, fluid properties and gas properties determine the flow area required to produce the target rate which also determines the nozzle and throat combinations that can provide the flow area without cavitating. Very small nozzles may not be able to provide sufficient energy even at a surface operating pressure of 5000 psi while large nozzles may reach the limits of acceptable fluid circulation rates in the tubing and casing size. Given the many sizes of nozzles and throats with the dynamic well parameters mentioned above provides an appreciation of the difficulty in answering the question of how much a jet pump can produce. The most acceptable simulation process based on an iteration process with a selected nozzle and throat and surface operating pressure which is greatly improved with computers, but these programs are not accessible to all.

Fluids returning to the surface must be separated and treated for reliable operation. Return fluid characteristics are considered in the design and selection of power fluid treatment systems that also send produced fluid to the production facility. Figure 7.0 is a diagram showing the two-vessel power fluid treatment system.

FEATURES AND BENEFITS OF HYDRAULIC LIFT

1. Multiple wells can be powered with one surface unit.
2. Hydraulic pumps can be installed deeper than most lift systems.
3. Applicable in severe doglegs, deviated or horizontal wells.
4. Several options are available to adapt pumps (RIGLESS) to a well’s existing completion.
5. Hydraulic pumps offer a wide range of lift and volume capacities.
6. High tolerance to sand, solids, paraffin and corrosion.
7. Tolerant to high gas production with gas vented well completions.
8. Reciprocating hydraulic pumps offer some of the highest efficiencies of any lift system.
9. Applicable for dewatering gas wells.
10. Recent success in Frac Fluid Recovery.
11. Hydraulic pump can pump from depths below perforations.
12. Hydraulic lift fluid circulation offers a way to send heated fluid or chemically treated fluid to the wellbore.
13. Hydraulic lift offer real time wellbore monitoring.
14. Hydraulic lift has been applied in wells producing from 20 bpd to over 20,000 bpd.
15. Hydraulic reciprocating pump have operated from more than 25,000 feet and jet pumps from more than 15,000 feet.

Why have some systems failed to give results?

1. Frequency of repairs sometimes required by the surface Pump: valves and plunger packing
2. Lack of the correct well completion design and equipment selection.
3. The needs for more research, development and diffusion.
4. The need to identify and control operating parameters.

SOLUTION FOR A MATURE OILFIELD

Aggressive oil recovery of the past has led to oil being left behind. This review of hydraulic lift was started as a result of work presented to recover an estimated 300,000 barrels from an oilfield near Lake Charles Louisiana. The field was discovered in 1907 with 490 wells drilled to produce 3.3 Million barrels of oil and 266 million cubic feet of gas in almost 100 years. Today, the field has 90 wells with 41 active and 49 plugged. The state demanded that the plugged wells had to be abandoned or reactivated.

The plan included slim hole or reduced bore drilling technology to reduce re-entry or drilling cost. But the 40% to 50% cost reduction in re-entry had to be complimented with an improved artificial lift system that would not compromise production in the reduced bore configuration. Slim hole or reduced bore drilling reduces cost by reducing casing size that also eliminate some BOP's, substructure, drilling rig size, volume of drilling fluids, mud treatment equipment, crew size and well completion cost to name of few.

The proven history of hydraulic lift was important to selecting it as the preferred lift system while recognizing that the system is known to offer solutions for the specific conditions.

WELL COMPLETIONS FOR MATURE LOW PRESSURE GASSY OILFIELDS

The beam pumping system is the traditional solution to low pressure gassy oil wells, but existing equipment was too old and small for the new targets. The close proximity of the wells to the central production facility led to consideration of a central hydraulic lift system where power to all the wells could be managed from one location with monitoring and remote control.

Review of the beam pumping system features identifies low back pressure on the formation or well bore the ability to separate gas and flow gas through the casing annulus. The hydraulic lift well completions that provide the same benefits include the parallel tubing string completion and the concentric tubing string completion where power fluid injection and return fluids are managed through separate routes from gas flow. Parallel tubing strings are limited to larger casing sizes unless the new parallel coil tubing fits inside the casing. The concentric coil tubing inside production tubing solution is the simplest selection, but requires updating the hydraulic lift completion. Traditionally hydraulic lift well completions have been left to the lift provider because pump performance simulations have been proprietary for many years, but lift system manufacturers do not normally offer coil tubing engineering or the accessories required to provide an engineered completion.

The advantage of hydraulics in this well completion is improved performance with deeper setting depths which require prudent consideration in water drive reservoirs with unfavorable contact, because increased production can lead to more water and less oil. The key is reservoir characterization and engineering. There are solutions, but keeping completions as simple as possible is best.

The jet pump performance best with pump intake pressures at or above 100 psi per hundred feet of depth or lift. Horsepower per barrel lifted above this "Rule of Thumb" or flag increases exponentially. The drawdown potential is usually better and at lower cost than gas lift in higher water cut wells, and very high gas production with production less than 150 bfpd would favor plunger lift. Very low production with limited gas and water production can consider the hydraulic piston pump for low cost oil recovery. The solution is an alternative to the high cost in some beam pumping applications in wells with severe dog legs.

CONCENTRIC COIL TUBING WELL COMPLETION

The well completion solution for hydraulic lift in low pressure gassy oil wells is to run the downhole pump in the well on or in coil tubing inside the production tubing so power fluid can be injected down the coil tubing and production mixed with exhaust power fluid return up the production tubing annulus. Gas is allowed to flow up the casing annulus. This concentric tubing and the parallel tubing completion have proven successful in many oilfields, with some still in operation after 20 years and with pump intake pressures less than 50 psi, GOR up to 6000 scf/bbl. and depths to 6000 feet. The beam pumping system works the same on the well and it too has proven to be a successful lift system in low pressure gassy oil wells.

Features provided by gas vented well completions include reduced backpressure on the formation and reduced gas flow through the pump. The jet pump is more tolerant of sand and gas. Gas does no harm to the jet pump, but large volumes can increases energy cost. It should be noted that small or moderate volumes of gas or gas in solutions reduce the weight of the return column resulting is less energy cost. Specific performance analysis is required to define each case.

Application design simulations confirm that jet pumps set below perforations gain sufficient pump intake pressure to provide improved efficiency; however, the hydraulic reciprocating piston pump provides the best possible OPEX when compared to jet pump horsepower to barrel produced.

Well Data- Concentric Coil Tubing Gas Vented Well Completion

Pump Depth: 4000’	Tubing: 2-7/8”
Casing: 5-1/2”	Power tubing: 1-1/2”
GOR: 700 scf/bbl.	Water Cut: 60%
Gas Sp. Gr.: .81	Water sp. Gr.: 1.01
WHT: 94°F	BHT: 141°F
SBHP: 1401 psi	PBHP: 1284 psi
WH Pressure: 100 psi	API: 31
Production @ PBHP: 113 Bfpd	

Jet pump performance simulations today are provided by several computer programs available on line; however, jet pump design programs have been proprietary to the manufacturers of jet pumps and often limit nozzle and throat selection to that manufacturer.

The results of the jet pump performance simulation shown in Figure 8.0 and table in Figure 9.0 indicate that 161 bfpd can be produced in the low pressure reservoir. This would include a nozzle flow area of 0.0115 square inches and throat flow area of 0.252 square inches requiring circulation of 725 bpd of power fluid at 4500 psi or 61 horsepower or 2.64 barrels per horsepower.

The same jet pump well completion can produce over 1000 bpd after drilling and simulation provided the pump intake pressure is greater than 100 psi per thousand feet of lift.

In comparison, a 2” piston pump model FE201313 produces 115 bfpd with a pump intake pressure of 150 psi with 195 bpd of power fluid at 1776 psi or 6.5 horsepower, (17.69 bpd per horsepower).

Plans are to clean and test re-entries with the jet pump and change to a hydraulic piston pump for long term economics. A central installation where one surface power unit provides power to several wells with a stand by unit to reduce down time is also planned.

HYDRAULIC LIFT WELL COMPLETION FOR WEST TEXAS

West Texas operators can tap several oil bearing rock formations that can enhance ROI, where artificial lift systems must produce high volumes when first installed after stimulation (hydraulic fracturing) and provide efficient pumping action months later with 40% to 60% less pressure and all the transitional well characteristics that come with lower reservoir pressures.

Beam Pumping has proven to be a solution in later stages but can be limited during start up. There are also occasional issues with well bores with severe dog legs, deviated or horizontal geometries that are not supportive of sucker rods. The benefits of hydraulic energy transmission around these wells bores was introduced in the mid 30’s and is going through an awakening in light of new drilling technology l issues that lead operators to seek solutions. The “Rig less” well intervention capacity of coil tubing also introduces a low cost solution to installation of a hydraulic pump without pulling tubing. Jet pumps are being run on coil tubing to provide solutions to otherwise troublesome wells.

Sample West Texas Well Data

Pump Depth: 9500’	Tubing: 2-7/8”
Casing: 5-1/2”	Power tubing: 1-1/2”
GOR: 1350 scf/bbl.	Water Cut: 70%
Gas Sp. Gr.: .81	Water sp. Gr.: 1.02
WHT: 105°F	BHT: 161°F

SBHP: 4501 psi | PBHP: 806 psi
WH Pressure: 100 psi | API: 41
Production @ PBHP: 150 Bfpd

Figures 10 and 11 above indicate that the target 150 bfpd can be produced at a pump intake pressure of 800 psi with about 640 bpd of power fluid at 3833 psi or 46 horsepower (3.26 bpd/ hp).

A 2” piston pump model 201313 can produce 150 bfpd at a pump intake pressure of 800 psi with 240 bpd of power fluid at 4136 psi or 19 horsepower (7.89 bpd/HP).

At present only a few operators take advantage of the piston pump in hydraulic lift. Most installations use the jet pump. It has also proven more tolerable to the sand and gassy production from unconventional reservoirs, but new oil prices may drive many to the economics offered by the piston pump in the long term.

HIGH VOLUME JET PUMPING

On high volume scenario with limited gas production and high reservoir pressure, Jet pumps have been reported to produce over 20,000 bfpd, but the more common targets do not exceed 3,000 bpd. High volume jet pump equipment use a special landing cavity that manages production inflow to the jet pump throat inlet to provide larger flow areas.

Larger internal flow areas provided in the high volume jet pump allow the use of larger nozzles sizes that put more horsepower downhole. Figure 12.0 shows the increase in flow areas of components that manage inflow from the well to the throat inlet.

High Volume Application

One of the larger populations of high volume jet pumps is in the northeastern plains region of Colombia where oilfields are not accessible for many months during the rainy season. The wireline recoverability of the jet pump provides a way to make changes or repairs “Rig less”.

The Miocene-Pliocene stage structure with monoclonal interrupted by progressively tilting or antithetical faults is highly permeable, (400-2000 mD) with porosity of 20% -28%, reservoir pressures around 2,500 psi and bubble point around 50 psi with several production zones. One of the target producing zones is also very close to water contact of a mobile water drive.

Control of reservoir pressure drawdown often reduces or stabilizes sand production and leads to producing bottomhole pressures greater than 1200 psi at the pump setting depth of 6000 feet providing more than 100 psi per thousand foot of depth, where jet pumps operate with low horsepower input per barrel produced. Power fluid circulation rates can be less than one barrel per barrel produced under these conditions.

The Jet pump’s ability to vary production rate with control of injection pressure and power fluid volume is also very beneficial in well testing the multiple zones in the selective completions. Testing is normally done immediately after drilling when reservoir pressures are high. Intervention to test multiple zones with jet pump is limited to wireline work and the jet pump allows for wide variations in production and lift capacity to test each zone while monitoring dynamic reservoir pressures.

The reverse flow jet pump is used in severe sand production to minimize sediment settling in the casing annulus, especially when the jet pump is located far above the packer in the casing free well completion. The jet pump is recommended after initial drilling when sand production is highest.

As the reservoir pressure declines to where pump intake pressure is 500 psi and water flooding results in higher production volumes while sand production stabilizes, the jet pump is moved to newer wells and an electric submersible pump is placed in the mature well.

Example High Volume Jet Pump Application- Casing Free Well Completion
Pump Depth: 7000’ | Tubing: 3-1/2”
Casing: 7” | GOR: 42 scf/bbl.
Water Cut: 91% | Gas Sp. Gr.: 0.8

Water sp. Gr.: 1.01	WHT: 91°F
BHT: 161°F	SBHP: 2100 psi
PBHP: 1500 psi and 1010 psi	WH Pressure: 100 psi

The jet pump performance simulation program results shown in Figures 14 and 15 indicate that a jet pump equipped with a nozzle diameter of 0.2099" amd throat diameter of 0.3841 resulting in a nozzle to throat area ratio of 0.3 requires 2903 bpd of power fluid at 3366 psi to produce 3007 bfpd at a pump intake pressure of 1500 psi. Horsepower required is 184 where one horsepower produces 16.34 bpd.

At lower reservoir pressure the same nozzle and throat combination requires 3296 bpd of power fluid at 3800 psi to produce 1731 bfpd at a pump intake pressure of 600 psi. Horsepower required is 236 where one horsepower produces 7.33 bpd.

Experience in this reservoir has proven the standard jet pump in either sliding sleeve or a standard style BHA does not meet the high volume production expectations.

In the same field recent test with standard model 2.81" jet pump adapted to a high volume BHA was equipped with a nozzle diameter of 0.2257" and throat diameter of 0.4056" was changed to larger nozzle and throat in an effort to increase production; however, the larger nozzle (diameter 0.2566") combined with a throat diameter of 0.4608" resulted in a loss of 650 bfpd. Note the nozzle to throat ratio remained the same. The high volume pump model previously installed in the same well had produced more and in line with theoretical performance predictions.

These high volume jet pumps have been reported to produce over 20,000 bfpd in other fields.

Years of observing wear patterns during repair inspections of the standard model jet pump that is run into standard landing cavities or sliding sleeves led to modifications and re-engineering. Note that jet pump performance simulation programs assume the user recognizes the limitations of the size and model of the jet pump and do not simulate conditions otherwise.

High volume equipment is usually installed in casing free well completions where power fluid is injected down the production tubing and mixed exhaust power fluid mixed with produced fluids flow up the casing annulus. When these systems are installed in solution gas or gassy reservoirs at operating points below saturation, the effects of liberated gas or gas surging can be minimized by increasing back pressure on the return flow. The jet pump is tolerant to gas, but high gas production can lead to increased horsepower per barrel lifted. Gas production that leads to less than 10 standard cubic feet per barrel of liquid at the discharge of the jet pump reduce the gradient of the return fluid column or the differential pressure that the jet pump has to provide to pump the well. This small amount also does not require large throat annulus areas. Larger volumes of gas production increase total volume that must be accommodated with large throat annulus areas which must still fall into an acceptable range of nozzle to throat ratio to obtain sufficient lift to pump the fluid. This normally results in increased power fluid which increases horsepower required to pump a barrel of fluid and may quickly reach the limits of the tubing and casing. This is where designing the completion for the life of the well should consider not only reservoir pressure decline, but secondary recovery, stimulation or EOR planning as well as potential changes in fluid properties. The surface equipment investment can remain the same, but the completion may have to be modified or installed with options that can allow modifications as the well changes.

HEAVY OIL SOLUTIONS

The piston pump successfully produced heavy crude from the Boscan field in Venezuela with 4" piston pumps and power oil for decades; however, the change to power water led to frequent pump failures and the removal of these systems in the late 80's.

It is worth observing that most successful cases involve power fluid heating, chemical treatment or mixing light oil from other fields. In cases where light oil is needed to help transport the heavy oil down the pipeline, injection of the same light oil downhole to power the jet pump has proven more effective.

There are numerous SPE papers written on comparisons of jet pump with electric submersible pumps and beam pumping systems showing the lower CAPEX and OPEX with hydraulics. In most cases monitoring systems were included at the jet pump suction and discharge as well and selected points in the system to provide critical operating data. This information allowed optimization of light oil mixing, heating or chemical treatment which was the basis for lower OPEX. Figure 16.0 is a diagram of a heavy oil

Power fluid plant heats power fluid and provides chemical treatment to optimize OPEX.

Well completions can be designed to conserve temperatures in heated systems and increase fluid return velocity as shown in Figure 17.0

THE INFORMATION AGE

Complete monitoirng systems have been part of electricsubmersible pumping systems and beam pumping systems for decades, but only recently has the hydraulic lift system been equipped with permanent downhole sensors and automated controls that are available with communication and remote control options. Figure 18.0 is a diagram of a permanent and retrievable quartz sensor that sits in a mandrel and transmits information electromagnetically to the mandrel which has cable communication with a surface digital aquisiiton unit. Data is sent to the varibale frequency drive PLC for transmission to the production engineer so he can optimize production, drawdown or other important parameters. Multiple sensors can monitor pump suction and discharge to optimize overall operation and production while providing insight to heating, and mixing.

Other operating parameters such as surface pressures, temperatures, power fluid treatment process and surface pump conditions as well as volume data with donwhole information also provide sufficient insight to equipment wear, trouble shooting as well as transient reservoir parameters. Communication systems keep teams in multiple locations aware of real time data.

Experience has shown that complex well conditions such as heavy oil can be produced with hydraulic lift, but systems must be designed with an integrated approach and benefit from monitoringand information where results have proven to lower cost.

PRODUCT DEVELOPMENT NEEDED

The downhole jet pump is the heart of the system. Inefficiencies and premature wear results in increased cost, downtime, pump recovery cost, repair cost, and in some completions heavy equipment cost. Materials and manufacturing technology is available today to provide a better more reliable jet pump.

Design compromises lead to less than optimum performance. Review of jet pump models is recommended in high volume production. One compromise in several jet pump models is the fixed spacing between the nozzle and throat. The component used to maintain a fixed nozzle to throat spacing has also proven to be an obstruction in high volume production. High volume production applications should use jet pump models that provide nozzle to throat calibration.

Engineered power fluid strainers can prevent premature nozzle plugging while factory pump performance test insure that the pump will do its job.

Figure 19.0 shows a diagram of the standard jet pump with the development in the crossover, which is the component that manages fluid inflow from the well. Improved materials of construction with modern manufacturing technology permit increased flow areas for lower pump internal pressure losses that result in more production and longer more reliable life.

SOLUTION TO A FREQUENT PROBLEM IN HYDRAULIC LIFT

The most frequently reported problem in hydraulic pumping are positive displacement surface pump valve and plunger packing failures. Many systems have been removed as a result of the surface pump maintenance. This is a surface pump and process issues that have solutions.

When the first hydraulic pumps were introduced over 80 years ago, each candidate well was analyzed and the power fluid process system was engineered to serve the specific needs. Power fluid had to [illegible] reciprocating piston pumps that required better quality fluid than the jet pump. The practice included sending the fluid to the oil fields existing oil and gas production process equipment that could include free water knock outs, three phase separators, heater treaters or special engineered process systems as shown in Figure 20.0. These diagrams are taken from a manual publish in 1961.

Jet Pump Crossover

Power fluid tanks equipped with gas boots and designed to minimize internal turbulence and supply sufficient gravity separation time to drop unwanted solids with tank diameter sufficient to provide an upward travel of 1 foot per hour and a tank height of 24 feet. The height was also sufficient to provide adequate "Net Positive Suction Head" to surface positive displacement pumps or could be assisted with centrifugal charge pumps. Figure 21.0 is a diagram of a power fluid tank design published in 1961.

The introduction of the unitized well site power fluid treatment in the 80's used pressurized vessels and cyclones to treat power fluid.

The well site power fluid treatment system shown in Figure 22.0 permitted the hydraulic lift system to compete with the beam-pumping unit and the electric submersible pump. The system received wide acceptance at a time when pumping unit manufacturing fell short of the industry needs. At one point, the two-vessel system became the answer to power fluid treatment for all wells, but it also led to an increase in surface pump maintenance along with a few learning experiences where the vessels would drop fluid levels in gassy wells with well completions that did not allow for gas venting.

There are several stories of systems shutting down due to low surface pump suction pressure as a result of gas surging. Well data predicted satisfactory performance but the wrong well completion led to build up of gas in "free state" under the packer. Gas would build up to the point that it slugged to the surface in volumes large enough to periodically empty fluid levels in the vessels.

Other systems failed to provide the results required due to poor operating practices. Operating or differential pressures that allow fluid to move through cyclones and vessels with sufficient pressure to prevent surface pump cavitation and feed production down the flowline are critical to the operation. Failure to maintain pressures resulted in complex problems. Engineered to the well characteristics and fluid/ gas volumes, the system performs satisfactorily; however, the system is not a "cure all". The cyclone requires a specific pressure differential to feed fluid through the cyclones. This pressure differential imposes a backpressure on the lift system requiring increased energy to produce. If there are not sufficient solids in the production to merit the use of the cyclone, increased economy is obtained without it.

There are also applications where oil characteristics, high temperatures, low water and high gas production can result in sufficient gas in solution at vessel operating pressures that gas release at the surface positive displacement pump suction causes abnormally high stress on all pump components, but the most frequent failures are the valves and packing.

Surface pump application engineering is essential to lower operating cost. Integrated engineering means considering the power fluid treating process systems, the surface pump and the entire surface and subsurface system including piping, and monitoring devices.

The surface pump should not be limited to positive displacement pumps.

Cases where existing production process equipment is distant from the well and wellsite power fluid treatment is necessary such as in the case of a low pressure, gassy unconsolidated sand formation with a strong aquifer in Indonesia. A 5' x 20' pressurized horizontal vessel provides adequate gas separation to feed a horizontal multistage centrifugal pump with some but limited entrained gas in the treated power fluid. The pump and power fluid treating system shown in Figure 23.0 operated for over 8 years with only preventive maintenance.

In this case, the extremely remote location could not consider process systems that could vent the fluid to atmospheric pressure, but the horizontal centrifugal surface pump (HPS) is more tolerant to small amounts of entrained gas. Positive displacement pumps installed before the HPS unit were experiencing failures weekly.

Another favorable option is the canned electric submersible pumps (ESP). Canned ESPs' were previously considered for offshore installations, but a canned ESP can reduce the environmental impact and can be designed to optimize gas separation. Fig. 24.0 shows a canned ESP where the well drilled to hold the pump can be sized to provide sufficient gas separation. The outer casing receives exhaust power fluid with produced fluid and gas. The inner casing hold water that drops to the bottom of the well and the ESP pumps the water to hydraulic pumps installed in other wells. Options to power the same multistage centrifugal pump, but powered with a standard industrial electric motor mounted on the wellhead are feasible in multiple wells that justify the pressurized seal and support system required at the wellhead. Excess fluids and gas in the outer casing flow down the flowline equipped with a back pressure valve.

One canned ESP can provide power fluid to multiple wells with minimum maintenance. The jet provides solutions to sandy, gassy, deviated or horizontal wells or wells with severe dog legs while the canned ESP provides maintenance free operation in a system with low environmental impact.

ADVANCES IN JET PUMPING: Continuous Umbilical Tubing Jet Pump

The search for lower cost and "Rig less" well intervention developed into a complete well completion. Re-engineering the jet pump with longer life potential creates an economical solution for mature oil wells.

Wells that require artificial lift or testing without removing the tubing can be equipped with a coil tubing jet pump with landing equipment that can be run "Rig less". Coil tubing is standard but a lower grade of continuous umbilical tubing (CUT) can increase savings. Examples of CUT well completions are shown in Figure 25.0. The concentric well completion allows injection of power fluid down the umbilical continuous tubing and production plus exhaust power fluid returns up the production tubing inside diameter. The pump can be set in a severely deviated well, directional well or horizontal well. It permits setting the pump in the horizontal and can be installed to take suction from the toe of a horizontal well.

Diameters are optimized to put the greatest amount of horsepower to the jet pump while providing the greatest possible return fluid flow area. The net effect is greater production and lift capacity.

Maximum power fluid injection pressure for hydraulic lift was established over 50 years ago when ancillary equipment was not available to allow higher pressures; however, technology today is available to inject pressures beyond 5000 psi at the surface. The new generation jet pump can be adapted with high-pressure connectors that allow power fluid injection pressures greater than 5000 psi. These higher pressures will be required as we probe toe of horizontal wells or deep wells.

The Continuous umbilical tubing installation unit as shown in Figure 26.0 is also a reduced version of the standard well intervention coil tubing unit. It is designed to install the jet pump completion at the lowest possible cost.

Ancillary equipment included are downhole landing and sealing assemblies, appropriate surface well pressure controls and high-pressure connectors as shown in Figure 27.0.

Wellhead pressure control equipment includes master ball valve, BOP, stuffing box, pumping Tee.

The completed system includes permanent downhole pressure and temperature monitoring instrumentation.

PRODUCTION TESTING ADVANCES

The Y-Tool solution for well intervention without removing the artificial lift system and pumping the well while logging is available with jet pumps for casing sizes that are not possible with the ESP. The design for 5-1/2" casing is already available.

Fig. 28 shows the a jet pump assembly that straddles a jet pump with an 1.87" outside diameter to 2-3/8" tubing to permit installation in 5-1/2" casing. Power fluid is injected down the tubing toe produce up the casing annulus. A plug can be placed in the HYDROLOG profile to operate the jet pump in normal operations or a logging plug can be installed to permit running through the Y-Tool with wireline or coil tubing and well intervention (logging) tools to perform activities while the jet pump is pumping the well.

CLOSING COMMENTS AND CONCLUSIONS

1. New continuous umbilical tubing hydraulic lift solutions allow "Rig less" installation of hydraulic lift for well testing offering reduced CAPEX and OPEX. Increased cost reductions are possible in combination with slim hole drilling.

2. Central surface power fluid plants minimize CAPEX and OPEX while providing solutions for special treatment in heavy oil production or gassy reservoirs.
3. The Y-Tool jet pump allows well testing and intervention while pumping the well and without removing the well completion or lift system.
4. The information age in hydraulic lift introduces solutions to historical process and maintenance issues and establishes parameters needed to optimize solutions in heavy oil recovery.
5. Successful hydraulic lift design that can meet the needs of a well through its productive life with optimum OPEX and CAPEX requires an integrated engineering approach that considers transient parameters, reservoir pressure decline and maintenance plans along with environmental and surface considerations.
6. Historical problems in hydraulic lift have solutions that require process engineering and potentially equipment alternatives that work best in the specific conditions, or thinking outside the box. This requires a more prudent understanding of the specific application.

Hydraulic lift needs increased development in order to offer solutions to todays and tomorrows artificial lift needs. The piston pump is a highly efficient tool that at one time pumped from 25,000 feet. There are obvious dimensional limitations to hydraulic power transmission in the confines of an oil well, but we have not upgraded many components with available technology that include but are not limited to materials of construction and manufacturing techniques. The coil tubing jet is also capable of meeting new challenges. There is much work to be done.

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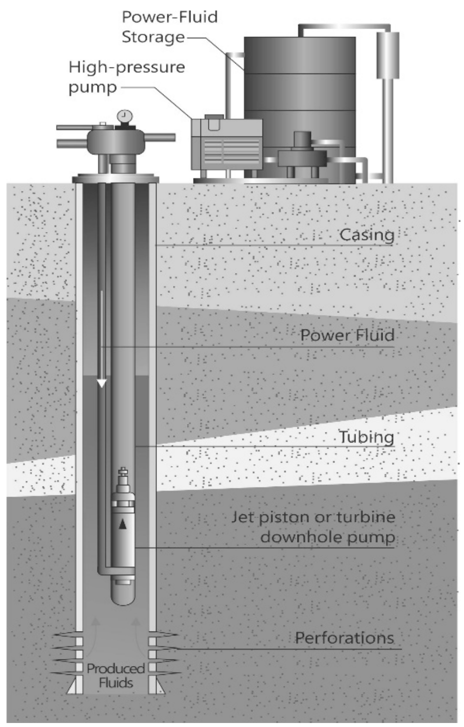

Figure 1.0: Major components of a hydraulic pumping system

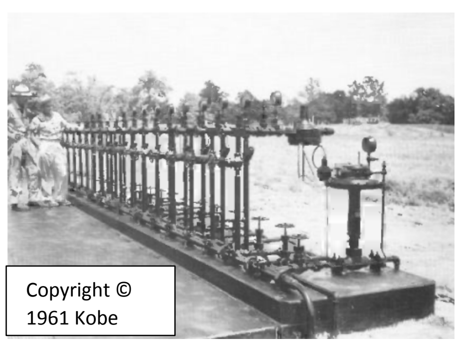

Figure 2.0 Power fluid manifold for multiple wells

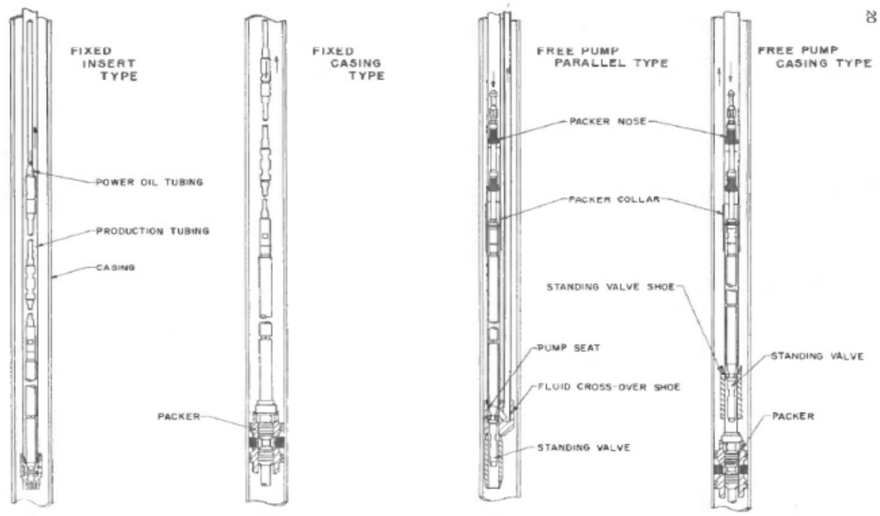

Figure 3.0: Common hydraulic lift well completions, Copyright © 1980, The Petroleum Publishing

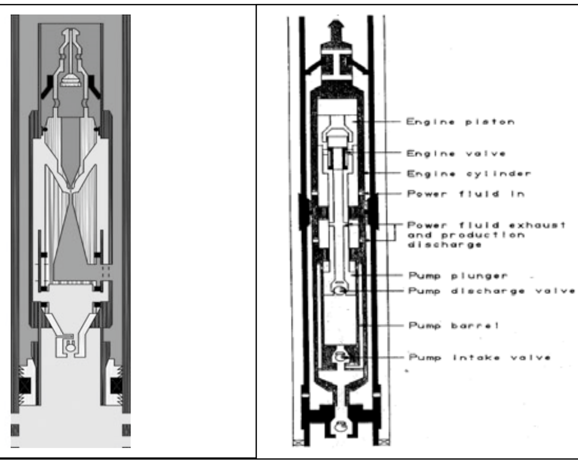

Figure 4.0 High volume jet pump and positive displacement piston pump, Copyright 1987 by the Society of Petroleum Engineers

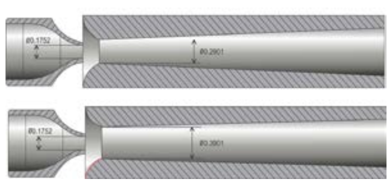

Figure 5.0 One size nozzle combines with different size throats to provide different lift or differential pressure.

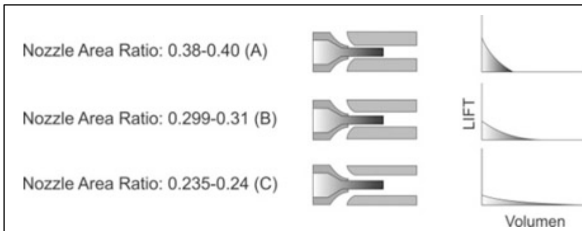

Figure 6.0 The same nozzle size combines with different throats to vary lift or Production capacity.

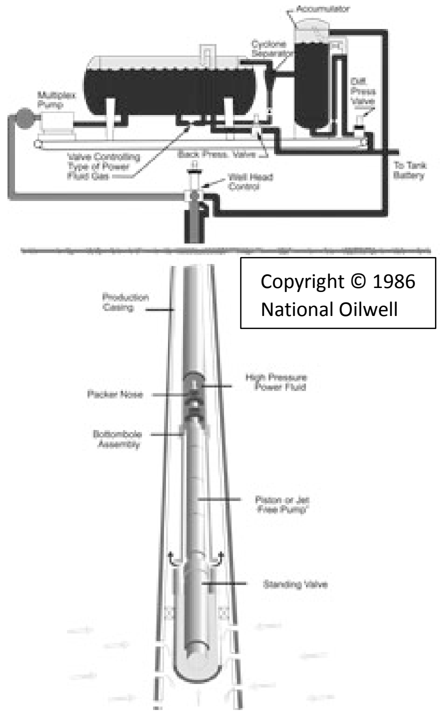

Figure 7.0 Two Vessel Power Fluid Treatment
system for remote applications.

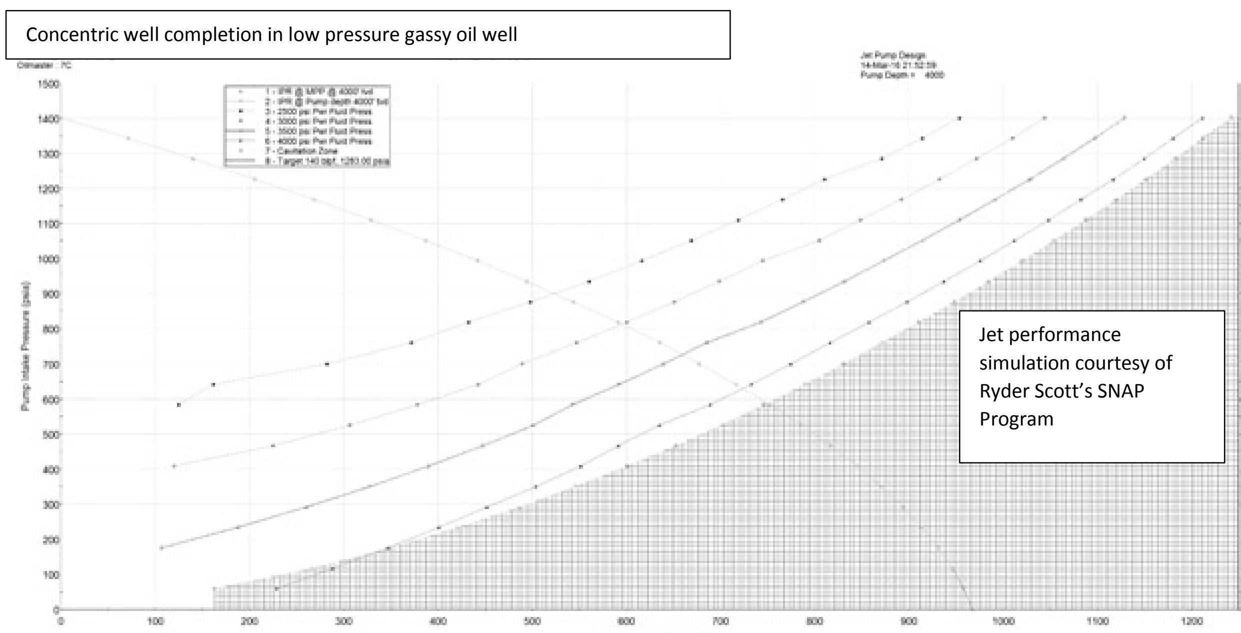

Figure 8.0 Jet pump performance curve for NAT 7C throat and nozzle in concentric 1-1/2" x 2-7/8"
completion

7C Pump Performance Summary

Target Production Rate : 140 BLPD @pump intake pressure : 1283 psia

Predicted Surface Power Fluid Injection Pressure	=	-189 psia
Predicted Surface Power Fluid Injection Rate	=	407 bpf/d
Predicted Pump Intake Pressure	=	1372 psi
Predicted Pump Discharge Pressure	=	1525 psia
Predicted Power Fluid Pressure at Pump depth	=	1553 psia
Predicted Horsepower requirement	=	-24 HP

Match Prod Rate (blpd)	Rate=	524	Rate=	595	Rate=	659	Rate=	724
Match Pwr Fluid Press (psia)	PFP =	2500	PFP =	3000	PFP =	3500	PFP =	4000
Match Pwr Fluid Rate (blpd)	QN =	741	QN =	803	QN =	860	QN =	915
Match Pump Intake Pres(psia)	PIP =	900	PIP =	812	PIP =	726	PIP =	629
Pump Discharge Prs(psia)	PD =	1798	PD =	1848	PD =	1899	PD =	1938
Match Pwr Fld prs @pmp (psia)	PN =	4100	PN =	4573	PN =	5048	PN =	5521

PmpInPr psia	Qresvr STB/D	QCav STB/D	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd
1401	0	1242	953	683	0	1044	741	0	1129	794	0	1211	843	0
1343	71	1212	914	690	0	1010	747	0	1097	799	0	1180	849	0
1284	140	1182	871	697	0	971	753	0	1063	805	0	1150	854	0
1226	206	1151	810	704	0	932	760	0	1028	811	0	1117	860	0
1168	269	1120	766	711	0	892	766	0	991	817	0	1082	865	0
1109	329	1087	718	717	0	848	772	0	953	823	0	1048	871	0
1051	387	1054	669	724	0	805	778	0	913	829	0	1012	876	0
992	442	1020	616	731	0	744	784	0	873	834	0	975	882	0
934	494	984	560	737	0	698	790	0	831	840	0	937	887	0
876	544	948	498	743	0	651	796	0	787	846	0	898	892	0
817	591	910	432	750	0	600	802	0	743	851	0	858	898	0
759	635	871	372	756	0	547	808	0	685	857	0	816	903	0
701	677	830	282	762	0	489	814	0	639	863	0	774	908	0
642	716	789	161	769	0	443	820	0	592	868	0	733	914	0
584	752	746	125	775	4	378	826	0	543	873	0	689	919	0
525	786	700	0	781	2	307	831	0	501	879	0	635	924	0
467	817	652	0	0	2	225	837	0	448	884	0	591	929	0
409	845	601	0	0	2	120	843	0	390	890	0	551	934	0
350	871	546	0	0	2	0	848	2	328	895	0	504	939	0
292	893	486	0	0	2	0	0	2	260	900	0	452	944	0
234	914	422	0	0	2	0	0	2	188	906	0	401	949	0
175	931	349	0	0	2	0	0	2	106	911	0	347	954	0
117	946	266	0	0	2	0	0	2	0	916	2	288	959	0
58	958	163	0	0	2	0	0	2	0	0	2	229	964	0
15	967	0	0	0	2	0	0	2	0	0	2	183	969	0
Maximum HP Required			HP =	38		HP =	50		HP =	63		HP =	76	

Fig 9.0 Jet Pump Performance Data Table (SNAP Program Results)

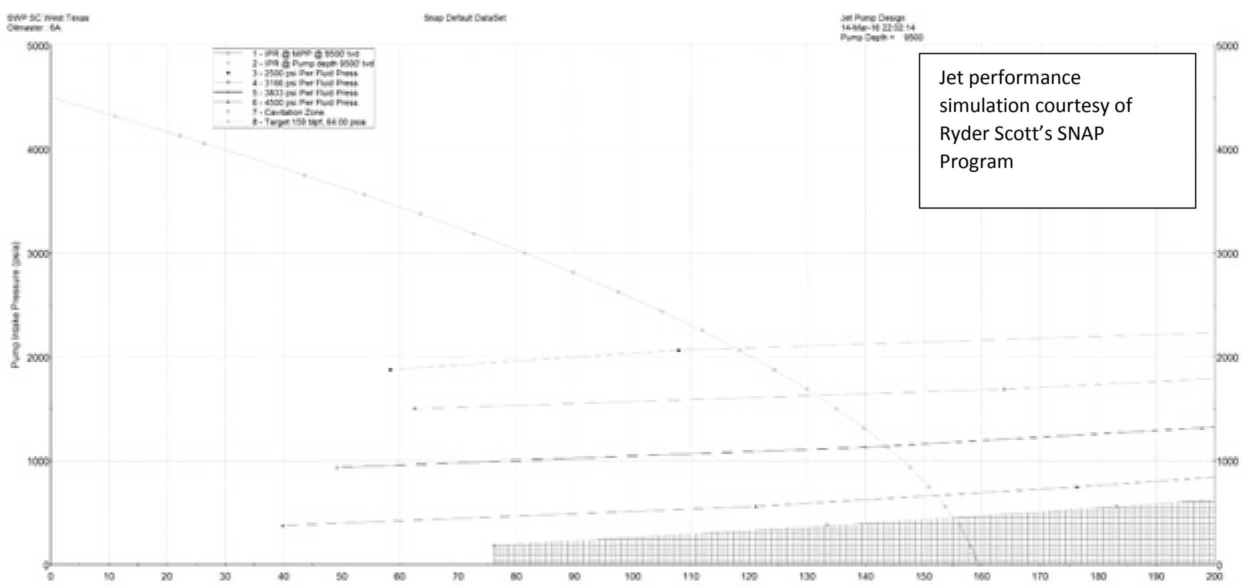

Figure 10.0 Jet pump performance for West Texas Concentric coil tubing completion

6A Pump Performance Summary

Target Production Rate : 159 BLPD @pump intake pressure : 64 psia

Predicted Surface Power Fluid Injection Pressure	=	5008 psia
Predicted Surface Power Fluid Injection Rate	=	931 bpf/d
Predicted Pump Intake Pressure	=	294 psi
Predicted Pump Discharge Pressure	=	4260 psia
Predicted Power Fluid Pressure at Pump depth	=	8737 psia
Predicted Horsepower requirement	=	93 HP

Match Prod Rate (blpd)	Rate= 118	Rate= 135	Rate= 144	Rate= 152
Match Pwr Fluid Press (psia)	PFP = 2500	PFP = 3166	PFP = 3833	PFP = 4500
Match Pwr Fluid Rate (blpd)	QN = 673	QN = 756	QN = 819	QN = 883
Match Pump Intake Pres(psia)	PIP = 2086	PIP = 1498	PIP = 1135	PIP = 658
Pump Discharge Prs(psia)	PD = 4148	PD = 4274	PD = 4201	PD = 4235
Match Pwr Fld prs @pmp (psia)	PN = 6498	PN = 7086	PN = 7688	PN = 8277

?mpInPr psia	Qresvr STB/D	QCav STB/D	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd
4501	0	854	9999	471	1	9999	534	1	9999	591	1	9999	642	1
4313	11	836	9999	489	1	9999	551	1	9999	606	1	9999	656	1
4126	22	817	9999	507	1	9999	567	1	692	620	0	734	670	0
4056	26	810	9999	514	1	640	573	0	684	626	0	726	675	0
3751	44	773	550	542	0	600	598	0	648	649	0	693	696	0
3563	54	736	521	558	0	575	612	0	625	662	0	671	709	0
3376	64	701	502	574	4	548	627	0	600	676	0	648	721	0
3188	73	667	455	589	0	518	641	0	574	689	0	624	733	0
3001	81	635	418	604	0	487	655	0	546	702	0	599	745	0
2813	90	603	373	619	0	453	668	0	516	714	0	571	757	0
2626	98	571	326	633	0	416	681	0	485	727	0	543	769	0
2438	105	539	277	647	0	375	694	0	452	739	0	515	781	0
2251	112	509	210	661	0	331	707	0	417	751	0	484	792	0
2063	118	478	108	674	0	287	720	0	377	763	0	452	803	0
1875	124	447	58	687	4	232	732	0	338	774	0	419	814	0
1688	130	414	9999	700	4	164	744	0	299	786	0	382	825	0
1500	135	381	0	713	2	63	756	4	252	797	0	347	836	0
1313	140	345	0	0	2	9999	768	4	198	808	0	309	846	0
1125	144	309	0	0	2	9999	780	4	140	819	0	268	857	0
938	148	269	0	0	2	0	791	2	49	830	4	224	867	0
750	151	228	0	0	2	0	0	2	0	841	2	176	878	0
563	154	183	0	0	2	0	0	2	0	0	2	121	888	0
375	156	133	0	0	2	0	0	2	0	0	2	40	898	4
188	158	76	0	0	2	0	0	2	0	0	2	0	908	2
0	160	0	0	0	2	0	0	2	0	0	2	0	0	2
Maximum HP Required			HP = 35			HP = 49			HP = 63			HP = 80		

Figure 11.0 Jet Pump Performance detail for West Texas (SNAP program results)

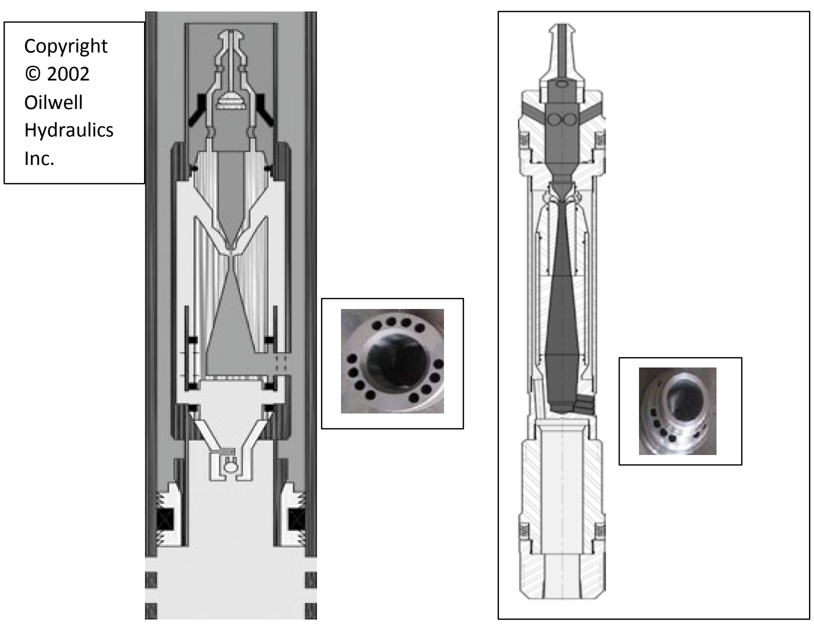

Figure 12.0 High Volume Jet Pump production inflow area vs the sliding sleeve jet pump inflow area.

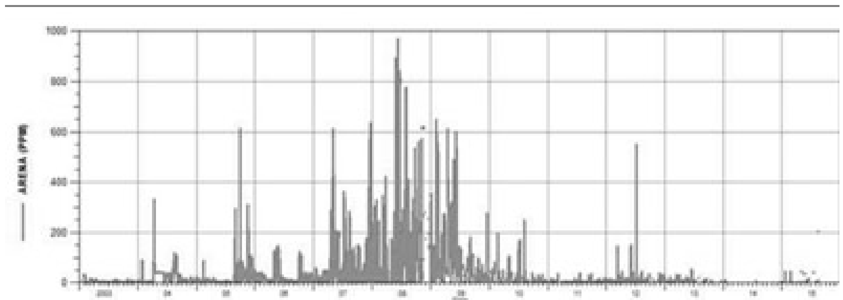

Figure: 13.0 Sand production on a C7 zone in the Casanare Region of Colombia where jet pumps is often used until sand stabilizes. Sand Production is known to exceed 3% of the total volume.

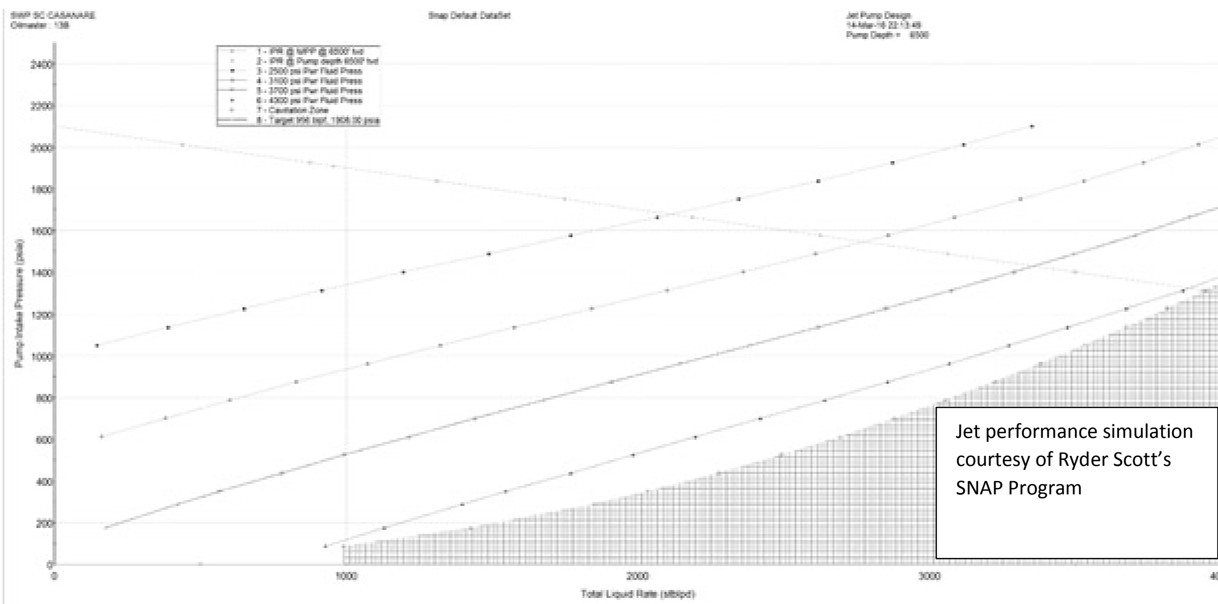

Fig 14.0 Jet pumps performance curve with a 13B nozzle and throat combination on the High Volume Assembly.

13B Pump Performance Summary

Target Production Rate : 956 BLPD @pump intake pressure : 1908 psia
Predicted Surface Power Fluid Injection Pressure = 1446 psia
Predicted Surface Power Fluid Injection Rate = 2798 bpf/d
Predicted Pump Intake Pressure = 1909 psi
Predicted Pump Discharge Pressure = 2902 psia
Predicted Power Fluid Pressure at Pump depth = 4353 psia
Predicted Horsepower requirement = 61 HP

Match Prod Rate (blpd)	Rate= 2114	Rate= 2773	Rate= 3358	Rate= 3889
Match Pwr Fluid Press (psia)	PFP = 2500	PFP = 3100	PFP = 3700	PFP = 4300
Match Pwr Fluid Rate (blpd)	QN = 3338	QN = 3645	QN = 3922	QN = 4177
Match Pump Intake Pres(psia)	PIP = 1677	PIP = 1545	PIP = 1428	PIP = 1322
Pump Discharge Prs(psia)	PD = 2917	PD = 2925	PD = 2937	PD = 2948
Match Pwr Fld prs @pmp (psia)	PN = 5383	PN = 5969	PN = 6556	PN = 7144

PmpInPr psia	Qresvr STB/D	QCav STB/D	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd	QSuctn STB/D	QNozzl B/D	cd
2100	0	4999	3351	3146	0	4108	3414	0	4741	3662	0	5292	3894	0
2013	438	4893	3116	3187	0	3922	3452	0	4584	3697	0	5159	3927	0
1925	875	4785	2873	3227	0	3733	3489	0	4421	3732	0	5022	3960	0
1838	1313	4674	2618	3266	0	3529	3525	0	4250	3766	0	4873	3992	0
1750	1750	4561	2346	3305	0	3312	3562	0	4079	3800	0	4721	4024	0
1663	2188	4445	2066	3344	0	3086	3597	0	3888	3834	0	4562	4055	0
1575	2625	4326	1770	3382	0	2858	3633	0	3703	3867	0	4397	4087	0
1488	3063	4203	1489	3420	0	2609	3668	0	3496	3900	0	4226	4118	0
1400	3500	4077	1195	3457	0	2361	3703	0	3289	3933	0	4042	4149	0
1313	3938	3947	916	3494	0	2101	3737	0	3073	3965	0	3869	4180	0
1225	4375	3813	649	3531	0	1841	3772	0	2848	3997	0	3675	4211	0
1138	4813	3673	389	3567	0	1576	3806	0	2617	4029	0	3473	4241	0
1050	5250	3529	145	3603	0	1324	3839	0	2385	4061	0	3273	4271	0
963	5688	3378	0	3639	2	1074	3872	0	2145	4092	0	3068	4301	0
875	6125	3221	0	0	2	828	3905	0	1910	4124	0	2857	4331	0
788	6563	3055	0	0	2	602	3938	0	1675	4155	0	2641	4360	0
700	7000	2880	0	0	2	381	3971	0	1441	4185	0	2419	4389	0
613	7438	2693	0	0	2	161	4003	0	1217	4216	0	2197	4418	0
525	7875	2493	0	0	2	0	4035	2	992	4246	0	1984	4447	0
438	8313	2276	0	0	2	0	0	2	779	4276	0	1769	4476	0
350	8750	2035	0	0	2	0	0	2	568	4306	0	1549	4505	0
288	9059	1845	0	0	2	0	0	2	422	4327	0	1399	4525	0
175	9526	1427	0	0	2	0	0	2	174	4366	0	1131	4561	0
88	9752	993	0	0	2	0	0	2	0	4395	2	929	4589	0
15	9860	0	0	0	2	0	0	2	0	0	2	768	4617	0
Maximum HP Required			HP = 178			HP = 245			HP = 318			HP = 388		

Figure 15.0 Jet pump performance results (SNAP program results)

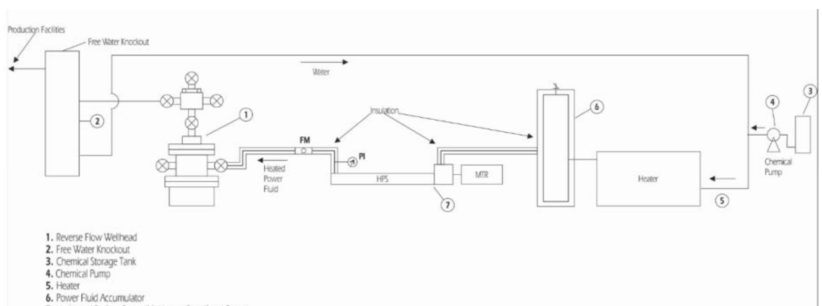

Figure. 16.0 Heavy oil power fluid treatment options

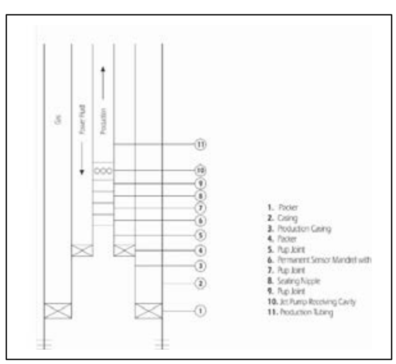

Figure 17.0 Heavy oil well reverse flow well completion

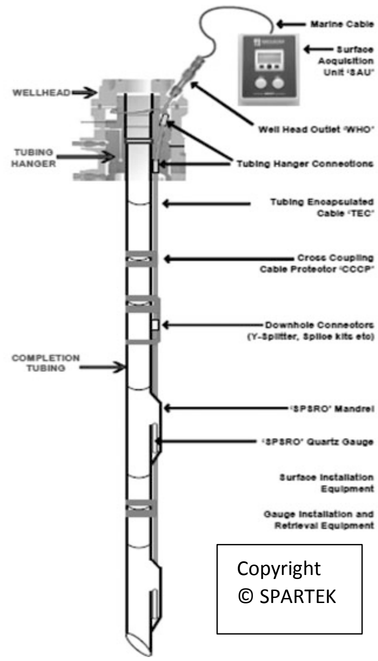

Figure 18.0 Permanent Recoverable Downhole Sensor

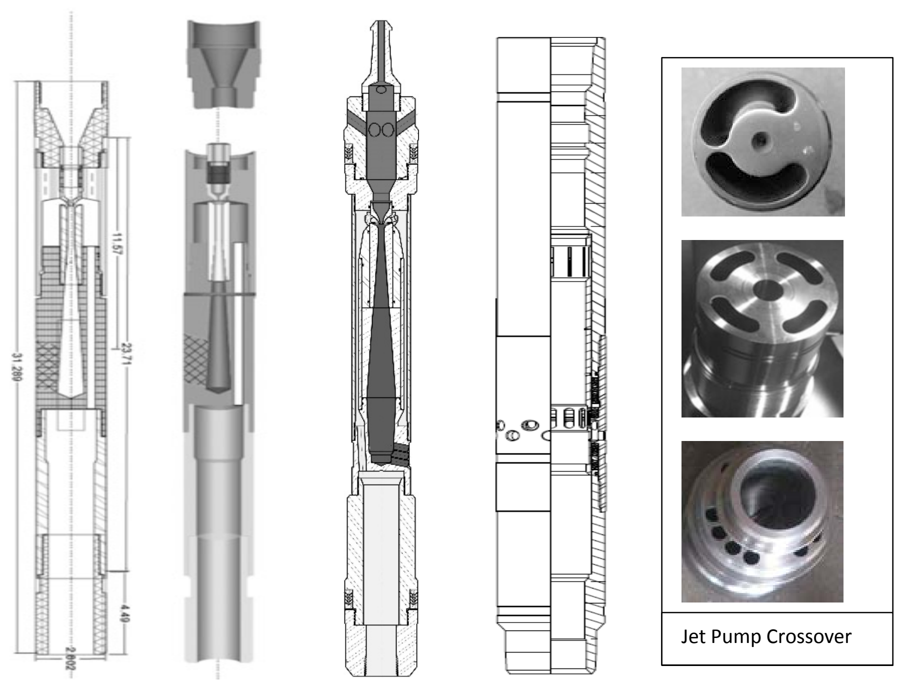

Figure 19.0 Old and New Generations Jet Pump that adapt to sliding sleeves with new generation crossovers.

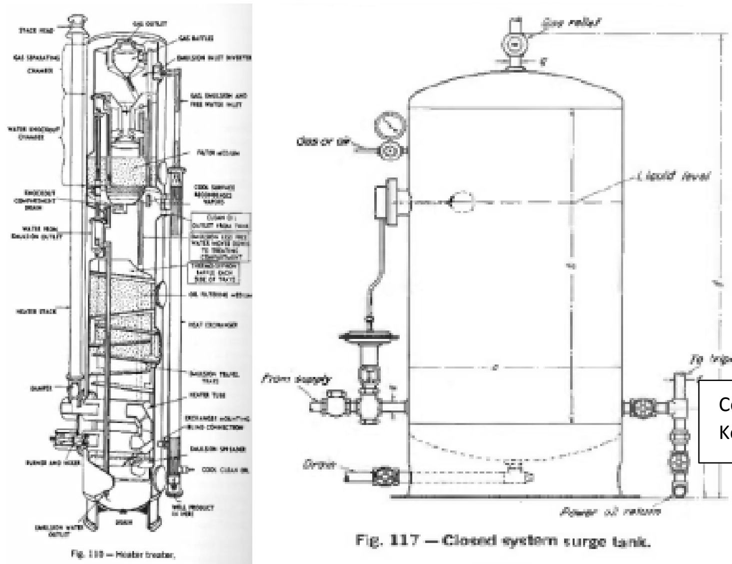

Figure 20.0 Engineered Hydraulic Heater Treater and Surge Tank

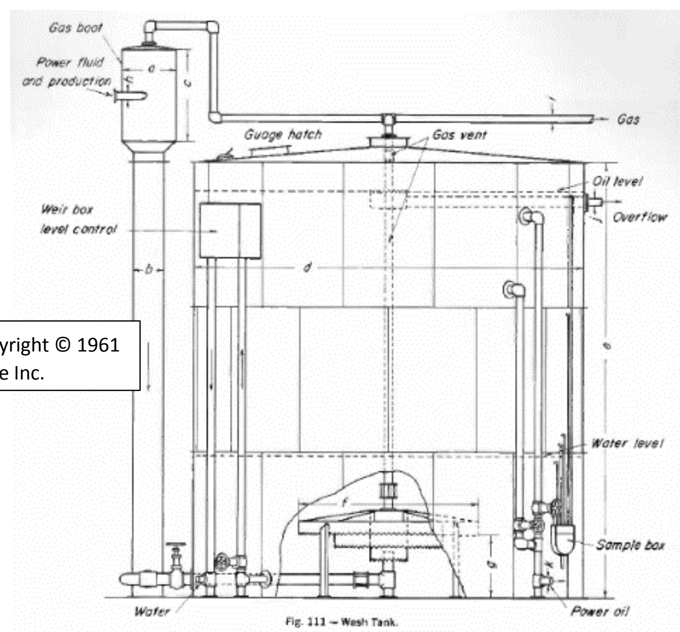

Figure 21.0 Power Fluid Wash Tank

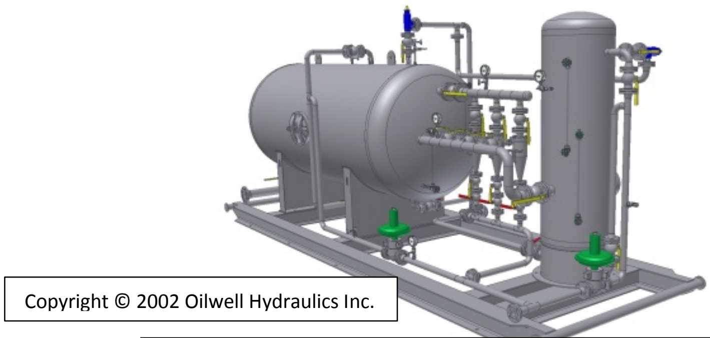

Figure 22.0: Two Vessel Power
Fluid Treatment System

Figure 23.0 Dual Vessel Power Fluid Treatment with Horizontal Pump-
8 years with no failures (PT PERTAMINA 2006)

.

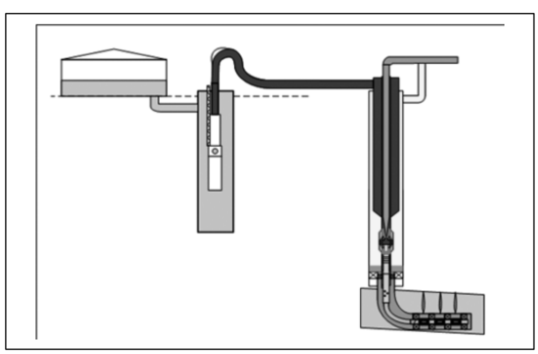

Figure 24.0 Canned ESP power pump

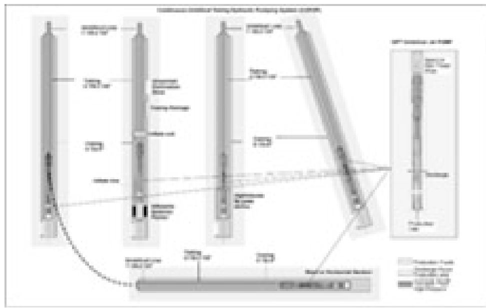

Figure 25.0 Continuous Umbilical Tubing or coil tubing jet pump extends the capacity of the concentric well completion.

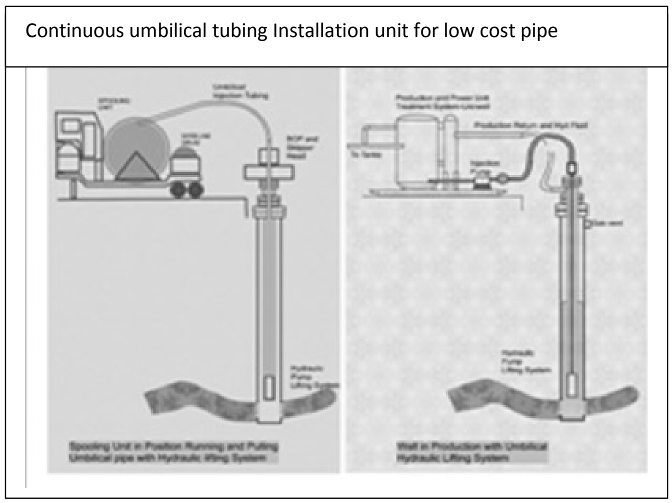

Figure 26.0 Simplified continuous umbilical tubing installation unit

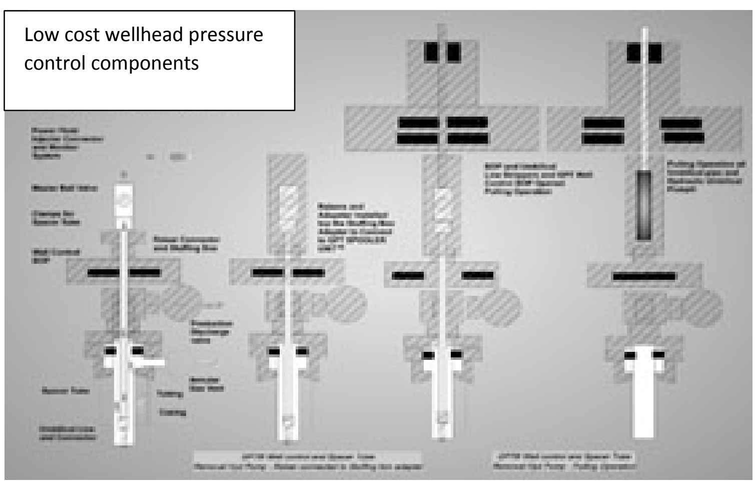

Fig 27.0 Wellhead Pressure Controls. Patent Pending

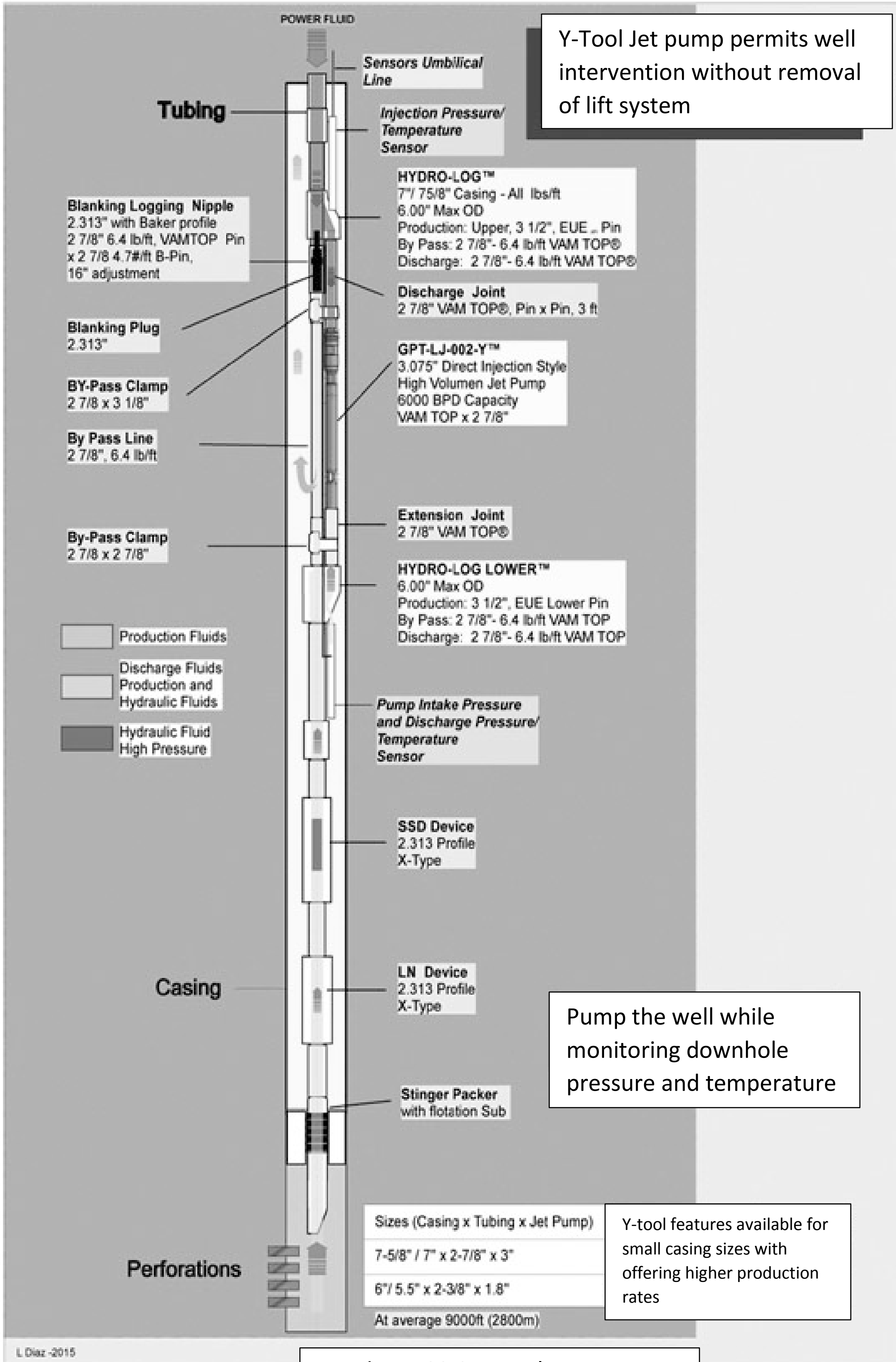

Figure 28.0 Y-Tool Jet Pump Assembly